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PROJECT NO. 52373

REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN	**§ §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

COMMENTS OF SIERRA CLUB

COMES NOW the Lone Star Chapter, Sierra Club and files these Comments in response to the Commission's Request for Comments on specific market redesign proposals. An executive summary of our comments is attached at the end of our more general comments.

The Lone Star Chapter of the Sierra Club has nearly 30,000 members throughout Texas, most of whom are located in the ERCOT region. We and our members have long advocated at the PUC, ERCOT, legislature and at local utilities and cities for clean energy, demand response and other distributed energy technologies, energy efficiency and adoption of building codes as ways to reduce energy demand and assure a more reliable energy grid.

These comments were prepared in consultation with James F. Wilson, Principal, Wilson Energy Economics. Mr. Wilson has 35 years of consulting experience to the electric power and natural gas industry,and has for many years been involved in market design and resource adequacy issues in PJM, New England, California, the midwest, and other regions. In particular, Mr. Wilson contributed to our analysis of the proposed LSE obligation.

We do want to say upfront in addition that ERCOT's energy-only market has generally performed well, and delivered affordable and reliable energy, but appreciate the need to consider reforms to provide greater reliability and safety for Texas consumers, especially considering the devastating events of last February. We do urge the Commission to carefully study and vet any major changes that are proposed before taking any specific actions.

In addition, we again want to remind the Commission that energy efficiency and demand response are the cheapest, cleanest and quickest ways to meet our energy needs. Energy efficiency is a useful investment to reduce overall demand, while demand response and price-responsive demand are demand reductions either in response to price or dispatch calls. Demand response contributes to efficient operation of the grid and balancing supply and demand in the short term.

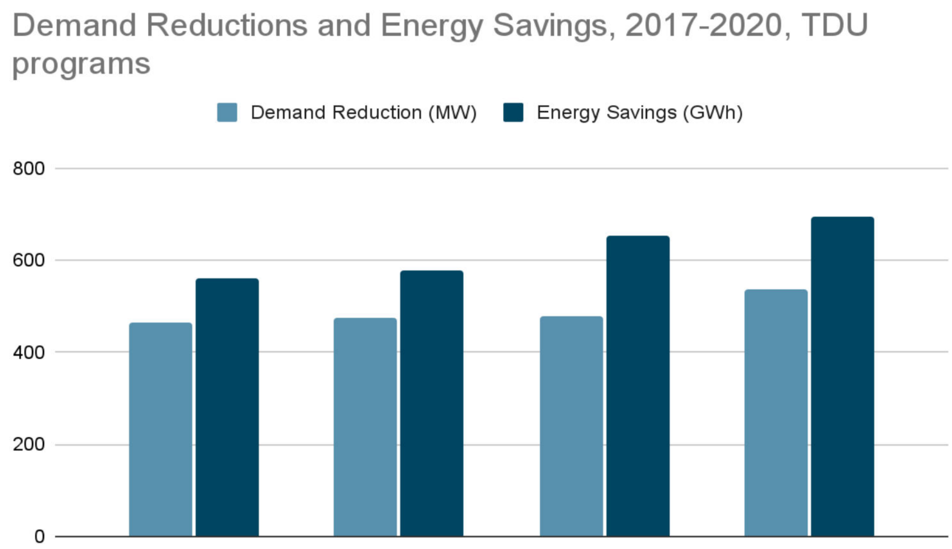
Consumers should have access to and have the option to participate in programs and where appropriate be paid for demand reductions. Customers, particularly those with limited incomes, should also have access to energy efficiency programs and new technologies like customer-sited and community-sited storage and solar resources. Thus, we emphasize the importance of engaging the demand side in the markets to a much greater extent, which helps balance supply and demand, contributes to reliability and moderates pricing.

We do want to emphasize that we agree with many other stakeholders that the Commission should consider a phased approach to any market solutions or changes, first focusing on actions that will improve market outcomes and can be implemented in a relatively short amount of time, while holding off on decisions regarding any major changes until they are properly studied and vetted. While we recognize the urgent need to assure that the events of last February are never again repeated, it would also be a mistake to hastily commit to a path involving major, fundamental changes that could undermine our market and the delivery of low-cost energy.

Along those lines, we do want to praise the Commission for taking some important steps already, such as weatherization requirements for the power sector. We believe that other changes that are being discussed such as an increase in ERS (including potentially utilizing it before EAA 1), changes to the ORDC, and continued encouragement to ERCOT to implement changes to ancillary services will increase reliability and can be implemented in the coming months.

In addition, we believe that the Commission should open a rulemaking to ensure that distributed generation -- including aggregation of distributed generation -- can compete fully in energy and ancillary markets, rather than just rely on ERCOT and its stakeholder process for these important changes. We also want to express our support for Chairman Lake's suggestion to look at ways to improve the use and usefulness of Smart Meter Texas (and other issues related to smart meters at the utility level) to spur greater energy management options for electric consumers.

Along these same lines, we also agree with the Chairman's support to move forward with a process to allow loads that are participants in our markets through demand response products to receive nodal prices, which will help with price formation and with creating more incentives for demand response. Finally, as we have previously stated, we believe that 10 years after the previous rulemaking, it is time to open the hood on the TDSP's load management and energy efficiency program. These programs have been cost-effective and beneficial but there are several issues that need to be addressed including the size of the programs, the mix of load management and energy efficiency programs, the size of the bonus and how it is calculated, the role of retail electric providers, and how to better incorporate winter savings and peak shaving programs, which have been limited. We have previously called for a more ambitious energy savings goal, such as one percent of overall residential and commercial energy use by 2025. Again, to be clear, we are supportive and appreciative of these TDSP programs, but believe that it is time for Texas to take a more proactive approach and right size the programs, which will benefit consumers and make the grid more reliable.



Note: 2020 Programs are estimated to have a lifetime cost of $0.02 KWH and $11.56 per KW.

Source: Tetra Tech, "Evaluation, *Monitoring and Verification (EM&V) of the Texas Investor-Owned Utilities' Energy Efficiency Portfolios*, Energy Efficiency Implementation Project, Presented to PUC, October 12, 2021.

Finally, as we have previously stated, while we recognize the many hours of time and effort of the Commissioners and staff, and stakeholders, normal Texans -- the public - have largely been absent from the discussion. We again call on the Commission to hold at least one public meeting to obtain input from the larger public on any proposed changes to our electric grid.

1. The ORDC is currently a "blended curve" based on prior Commission action. Should the ORDC be separated into separate seasonal curves again? How would this change affect operational and financial outcomes?

The Sierra Club is generally supportive of the changes under discussion to the ORDC curve. First, we are supportive of the idea of having seasonal curves to match the reality of the grid as opposed to a blended curve. Load levels and shapes, and resources and resource performance, are quite different in different seasons, suggesting different ORDCs with different shapes. This leads to certain seasons being "richer" for generators than others, but this would better match the needs of the grid, and help incentivize demand response when it is most needed to match supply and demand.

In addition, we are supportive of lowering the HCAP to some figure between $4,500 and $6,000 which would still incent demand response for most electric consumers, but create a less steep slope toward a $9,000 cap.

Moreover, we are open to the idea of extending the MCAP to either 3,000 or even 3,200 MWs which would increase the number of hours in which the ORDC is applied.

Finally, we feel strongly that the ORDC prices should be available to any resource that provides energy during those hours, be it from a distributed resource, fossil fuel or renewable resource. The ORDC is meant to be an incentive for generation (and demand response) during times of scarcity, at least until real-time co-optimization is fully implemented.

2. What modifications could be made to existing ancillary services to better reflect seasonal variability?

We believe that the Commission and ERCOT will be well served by focusing on changes to the energy and ancillary markets that can be implemented in a non-discriminatory manner, and in a relatively short time frame.

We are supportive of recent changes made at ERCOT that allow loads to participate in a larger portion of RRC, as well as in NSPS, the creation of a Fast Frequency Response Service and the decision to begin a new ancillary product known as ERCS. We agree with Chairman Lake's memo that ERCOT should continue to develop these products. ERCOT has also been making major changes in the use of Non-Spin. We are supportive of the decision that could lead to non-controllable loads providing non-spin and continue to be engaged with other stakeholders about the correct duration, response, and volume (i.e. minimum size and overall size) requirements.

ERCOT should continue discussions about how to refine the use of non-spin and consider the need to create NSPS of different durations, such as one-hour, three-hour and six-hour products. This would allow, as an example, batteries to provide non-spin for shorter durations, and loads and more traditional generation to provide longer duration needs when there are sudden changes in net-load that last more than an hour or two. ERCOT has recently begun contracting for additional amounts of non-spin based on variability risk due to changes in weather, demand or variable resource output and this may be a good approach to deal with seasonal issues. We have previously suggested that a peak-ahead service may be warranted that would be contracted through a market approximately six-hours before the peak period as a way to provide another service to assure reliability, though we believe the Non-Spin product (and eventually ECRS) can serve this function. ERCOT is currently setting monthly totals for 2022 through the stakeholder process for ancillary services, but these can be adjusted as needs arise and as conditions change on a daily basis with ERCOT's new methodology.

In addition, we continue to believe that ERCOT and the Commission should reconsider an idea that has previously received stakeholder support but has never been implemented - multi-interval SCED, also known as MIRTM - a Multi-Interval Real Time Market. A market that allowed bids into several time periods such as 30 minutes or an hour would allow more participation by demand response, distributed resources and quick start resources like gas plants and batteries. A MIRTM would improve the efficiency of the short term commitment decisions, dispatch and pricing of resources such as storage and distributed generation, combustion turbine Generation Resources and Load Resources providing demand response by coordinating the commitment and honoring the resources' temporal constraints and by reflecting the physical realities of the system.

It would also allow ERCOT operations more understanding of what resources are available and likely to show up when net load is high. Such a look-ahead market would take time to implement but we believe would enhance the move to real-time co-optimization and allow a better mix of market and ancillary service participation. Indeed, to reduce costs it should be implemented along with co-optimization. We call on the Commission to analyze how development of a 30-minute or one-hour multi-interval real-time market could improve reliability.

3. Should ERCOT develop a discrete fuel-specific reliability product for winter? If so, please describe the attributes of such a product, including procurement and verification processes.

While we acknowledge there may be value in assessing the development of a fuel-specific reliability product, Sierra Club is not convinced that some kind of discrete fuel-specific reliability product for winter is needed, and has many concerns about how such a product would be defined and utilized. We recognize that the terrible consequence of winter conditions that led to hundreds dead and millions without power would suggest the need for some sort of storage requirement, but believe the main way to address the issue is through winterization requirements. Indeed, the ERCOT analysis of those fateful days found that the principal problems were many generation resources being off-line, many generation resources failing to have their equipment weatherized, and many resources not having accessible fuel, due to the fuel supply not being weatherized. Thus, as we previously stated, recent action by the PUC to require a Phase 1 weatherization of all power sources, and inspections and action being taken by the Railroad Commission (which have not been sufficient in our view) should help mitigate future issues. Second, the other major reason there were such problems those days was the huge jump in residential demand, much of it caused by inefficient, leaky homes and heating systems.

We thus repeat again that specific demand reduction and energy efficiency programs focused on insulation, heat pumps and smart thermostats could largely reduce the risk of similar situations in the future. We believe that the current ancillary products, with perhaps the development of an "uncertainty product" (as proposed by Potomac Economics in its presentation on October 14th) for two-hour to six-hour periods when the system is at risk, may be sufficient. As an alternative, ERCOT could also create a winter non-spin product where those resources with fuel-based capabilities such as fuel stored on site could be chosen first before those that lacked such a capability.

a. How long would it take to develop such a product?

We are concerned that it may not be possible to come up with a reasonably effective and efficient design for discrete fuel-specific reliability products for winter. Accordingly, we believe that the design of such products would take a considerable amount of time. In addition, we anticipate that the design of such products would be controversial, because it will necessarily involve many rather arbitrary determinations (how firm, for how long, when is the product dispatched, etc. etc.) that affect different resources differently, among many other challenges.

b. Could a similar fuel-based capability be captured by modifying existing ancillary services in the ERCOT market?

There is some potential to modify existing and proposed new ancillary services to bolster the firmness of these services. This could take the form of additional eligibility requirements to provide the services, choosing those with dual-fuel or storage capability first, and/or stronger penalties for non-performance. Designing changes to strengthen existing ancillary services would be much easier than designing new fuel-specific reliability products.

4. **Are there alternatives to a load serving entity (LSE) Obligation that could be used to impose a firming requirement on all generation resources in ERCOT?**

At this time, we are not convinced that imposing a firming requirement on generation resources in ERCOT is necessary to achieve adequate reliability. We are concerned that such a requirement, whether imposed through an LSE Obligation or in another manner, would impose unnecessary costs on consumers and discriminate against renewable resources.

As noted under 3b above, we believe there may be some potential to modify existing ancillary ancillaries to bolster the firmness of these services.

In any case, no decision should be made about a firming requirement, or an LSE Obligation, without further study of the possible design approaches, the likely costs to consumers, and unintended consequences.

5. **Are there alternatives to an LSE Obligation that could address the concerns raised about the stakeholder proposals submitted to the Commission?**

Again, we believe that the Commission should focus on the energy and ancillary services markets, and on the demand side of the grid, in the near term.

If the Commission were interested in a program to help particularly assure that seasonal peaks, the Commission could create a residential peak demand reduction goal for LSEs. Thus, as we have previously suggested, the Commission could -- perhaps based on a potential study -- direct all LSEs to meet a certain percentage of residential peak load with demand response and distributed generation resources, either under contract or through a trading mechanism. This would keep LSEs out of the business of generation, but create a market for demand response and distributed generation that is more in keeping with our deregulated market.

Load Serving Entity (LSE) Obligation

We offer the following preliminary observations on the LSE Obligation proposal: As explained above, we believe the ERCOT energy and ancillary services markets have generally worked well, and ERCOT's approach to the wholesale markets should be maintained and further developed. ERCOT's Energy and Ancillary Services markets acquire and price the various services ERCOT needs to manage the grid reliability, forming prices at a very granular level to guide investments in the types of resources that can provide the valued operating characteristics at lowest cost. The LSE Obligation would shift much of this revenue to an administrative obligation "product" imposed on LSEs, attracting different resources and reducing and distorting energy and ancillary services prices.

We are concerned that the LSE Obligation is a fundamental change that abandons the energy-only approach and shifts to something more similar to the eastern markets that include administrative "capacity markets." Contrary to the proponents' suggestion that the LSE Obligation would be a "light touch regulatory overlay" (E3 presentation slide 3), we believe the LSE Obligation would ultimately look a lot like a capacity market, and would be as complex and controversial to design and implement.

6. How can an LSE Obligation be designed to protect against the abuse of market power in the wholesale and retail markets?

> **a. Will an LSE Obligation negatively impact customer choice for consumers in the competitive retail electric market in ERCOT? Can protective measures be put in place to avoid negative impact on customer choice? If so,please specify what measures.**
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> **c. What is the impact on self-supplying large industrial consumers who will have to comply with the LSE Obligation and will it impact their decision to site in Texas?**
>
> **d. What is the impact of an LSE Obligation on load-serving entities that do not offer retail choice, such as municipally owned utilities or electric cooperatives?**

See our other comments on the LSE Obligation proposal under questions 6 through 12; we defer to entities directly involved in customer choice, to industrial customers, and to LSEs that do not offer retail choice, respectively, for more detailed responses to parts 6a, 6c, and 6d.

b. **How can market power be effectively monitored in a market where owners of power generation also own REPs that serve a large portion of ERCOT's retail customers?**

e. Can market power be monitored in the bilateral market if an LSE Obligation is implemented in ERCOT? Can protective measures be put in place to ensure that market power is effectively monitored in ERCOT with an LSE Obligation?If so, please specify what measures.

f. Should the LSE Obligation include a"must offer"provision? If so, how should it be structured?

As suggested by Question 6, the potential for exercise of market power is a substantial concern under the LSE Obligation proposal. The proponents of this approach have not addressed this problem at all.

The ownership of generation is highly concentrated in ERCOT.[1] That ensures that some generation owners would have strong incentives to economically withhold their capacity by demanding very high prices to agree to enter into a commitment to satisfy an LSE's assigned obligation. The owners of large generation portfolios might also demand a very long-term commitment. This market power would likely drive the cost of meeting LSE Obligations to or above the cost to build new power plants, even when new capacity is not needed.

In addition, as suggested by Question 6b, in ERCOT some retail electric providers are affiliated with generation owners. This raises the prospect of discriminatory access to capacity to satisfy the LSE obligations, if these generation owners offer affiliated REPs more favorable conditions than unaffiliated REPs.

And as suggested by Question 6e, because the LSE Obligation proposal calls for a bilateral market, there would be no transparency with respect to the negotiations and ultimate contractual relationships between generation owners and LSEs. While reporting requirements could be imposed, the ultimate contractual arrangements could be quite complex -- they might involve multiple resources, and multiple services, for various periods of time, and with various pricing and risk-sharing provisions, to note just a few possible provisions. This complexity could render it impossible to identify a price paid to satisfy the LSE Obligation, or to compare one deal to any other.

As suggested by Question 6f, the Commission could consider trying to impose a "must offer" requirement, to prevent generation owners from physically withholding some of their capacity from LSEs to raise the prices and cost of satisfying LSE Obligations. A "must offer"

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[1] Potomac Economics, 2020 State of the Market Report for the ERCOT Electricity Markets, May 2021 (see pp. 87-96, pp. A-43 - A-59; for example, stating p. 88 that pivotal suppliers existed in 22% of all hours in 2020)]

requirement, if legally permissible, could mitigate physical withholding to some extent though of course generation owners could still physically withhold a resource by simply announcing plans to retire it. However, if prevented from physically withholding, generation owners could simply economically withhold by demanding very high prices. (The Commission would not be able to impose both a "must offer" and a maximum offer price, as that would amount to confiscation of the asset).

It is a matter of simple economics that if the demand for capacity is inelastic (as it would be under an imposed LSE Obligation), and the ownership of the capacity is concentrated, the owners of large portfolios would have both the ability and incentive to economically withhold a portion of their capacity, to to drive up the prices to satisfy LSE Obligations, increasing the revenue to the overall portfolio. And while the owners of smaller portfolios might not have the incentive to economically withhold, they also would have no reason to settle for lower prices than the large players were demanding. While it is fairly predictable how this would play out, it won't be transparent, because the negotiations and resulting contracts will be bilateral, confidential, and potentially complex.

To summarize, we believe the LSE Obligation would lead to substantial market power that cannot be effectively monitored or (more importantly) mitigated, and that this will result in high prices and costs to satisfy the LSE Obligations, and discriminatory access to capacity.

7. How should an LSE Obligation be accurately and fairly determined for each LSE? What is the appropriate segment of time for each obligation? (Months? Weeks? 24 hour operating day?12 hour segments? Hourly?)

8. Can the reliability needs of the system be effectively determined with an LSE Obligation? How should objective standards around the value of the reliability-providing assets be set on an on-going basis?

a. Are there methods of accreditation that can be implemented less administrative burden or need for oversight, while still allowing for all resources to be properly accredited?

b. How can winter weather standards be integrated into the accreditation system?

Questions 7 and 8 address the quantity aspects of the LSE Obligation proposal: how would the total quantity (and its seasonal and hourly "shape") be determined, how would the quantity and shape be assigned to LSEs, and how would the amount of the obligation each particular resource can satisfy be determined. These are important and complex questions; and answers to these questions would be highly controversial and ultimately rather arbitrary, involving numerous administrative determinations.

Under the proposal, ERCOT would determine the LSE Obligations on a three-year forward basis. To do this, ERCOT would employ a model to simulate the loss of load expectation ("LOLE") in each hour of the future year. Each LSE's Obligation would then "be based on each LSE's pro-rata share of firm (non-curtailable) load during periods in which there is a non-zero probability of a reliability event." E3 presentation slide 9. Thus, the LSE Obligation would be complex, and be defined in reference to many different hours, at different times of day and in different seasons, when non-zero LOLE occurs in the simulation. Furthermore, the seasonal and hourly "shape" of the LSE Obligation would be highly dependent on the assumptions about the resource mix, and in particular the assumptions about the quantities of wind, solar and energy storage resources, that can shift loss of load to different seasons and hours.

To run such a model, ERCOT would have to make assumptions about the ERCOT resource mix three years into the future. The resulting LSE Obligations, and also the ELCCs of all resource types, depend on this model and the assumed load shapes and resource mix used in the simulation.

This will all be very complex and controversial, as all the details will affect different resources and different LSEs differently.

The proposal also requires establishing a "formal reliability standard" (E3 presentation slide 7), such as the common "one day in ten years", or a modern equivalent. If the Commission sets this standard to accomplish roughly "one day in ten years", as is done in capacity markets and most utility integrated resource plans, the LSE Obligations will reflect a substantial reserve margin and quite low resulting loss of load expectation. In essence, Texas and ERCOT will have abandoned the energy-only market approach and instituted something similar to a capacity market in its cost and impact.

If instead the Commission sets a lower standard, more consistent with the value consumers actually place on resource adequacy (various estimates place "one day in ten years" as one or two orders of magnitude higher than that, with an implied Value of Lost Load over $150,000/MWh [cite: Technical Conference Comments of David B. Patton and Pallas Van Schaick of Potomac Economics, Ltd, FERC Docket No. AD21-10, Modernizing Electricity Market Design, March 22, 2021, page 12), then the LSE Obligation might be less costly, but the proposal might not result in a quantity of capacity that would provide much assurance that resource adequacy will be accomplished, without other measures.

Another very difficult question is whether and to what extent the LSE Obligations will be zonal. If the obligations are only system-wide, the mechanism would not ensure that ERCOT has the capacity it needs where it is needed for reliable operation. If the obligations will be zonal to any extent, there are many difficult questions about how the zones are identified and defined, how the zonal obligation quantities are sent, and how those zonal obligations are assigned to LSEs. This has been one of the many complex and controversial issues that has come up over and over again in regard to the capacity markets in PJM, ISO New England, and NYISO.

9. **How can the LSE Obligation be designed to ensure demand response resources can participate fully and at all points in time?**

The process to identify the amount of an LSE Obligation each resource can satisfy, addressed above, must also apply to demand response in a non-discriminatory manner.

10. **How will an LSE Obligation incent investment in existing and new dispatchable generation?**

The LSE Obligation proposal does not provide any specific incentive for dispatchable generation, and this characteristic could not be added to it.

Even the complex capacity markets administered by PJM and ISO New England do not specifically incent dispatchable generation.

11. **How will an LSE Obligation help ERCOT ensure operational reliability in the real-time market (e.g., during cold weather events or periods of time with higher than expected electricity demand and/or lower than expected generation output of all types)?**

Resources that enter into agreements to satisfy an LSE's obligation will be subject to performance requirements and penalties for non-performance.

12. **What mechanism will ensure those receiving revenue streams for the reliability services perform adequately?**

This will require detailed rules regarding performance requirements, performance measurement, and penalties for non-performance. These details will necessarily entail many arbitrary parameters and will be very controversial, as the manner in which each parameter is set advantages some resources and disadvantages others depending upon their particular operating characteristics.

13. **What is the estimated market and consumer cost impact if an LSE obligation is implemented in ERCOT? Describe the methodology used to reach the dollar amount.**

This could range from extremely high (higher than the cost of a full capacity market) to extremely low, depending upon the parameters chosen.

At the low end, in the unlikely event that the obligation amounts are set so low that the obligation is not triggered, or there is sufficient excess capacity that market power cannot be exercised, the cost of resources to meet the obligations could be low. We do not believe this is at all likely to be the case given the concentration of generation in ERCOT and the need to set a substantial obligation quantity if it is intended to ensure resource adequacy.

At the high end, if, as expected, the owners of large portfolios demand high prices, the cost of satisfying the LSE Obligations would be high. In fact, because the bilateral negotiations are potentially less efficient than a centralized auction mechanism (due to the lack of price discovery), the LSE Obligation proposal could potentially be even more expensive than the highly costly and controversial capacity markets operated by PJM, ISO New England, and New York ISO.

14. How long will the LSE Obligation plan take to implement?

As noted above, ultimately the LSE Obligation proposal would be very complex to design, and very controversial. The Commission should assume it could take years to even have a detailed design for stakeholders to fight over.

15. If the Commission adopts an LSE Obligation, what assurances are necessary to ensure transparency and promote stability within retail and wholesale electric markets?

As noted above, a bilateral market by its nature does not provide transparency, and due to the potential complexity of the negotiations and ultimate agreements, even a reporting requirement might not provide much transparency.

16.Are there relevant "lessons learned" from the implementation of an LSE Obligation in the SPP, CAL-ISO, MISO, and Australian markets that could be applied in ERCOT?

The LSE Obligation mechanism that has been proposed for ERCOT has not been implemented in any other market; it is quite different from the resource adequacy constructs in SPP, California, Australia, or anywhere else. Furthermore, the ERCOT market and regulatory circumstances are very different from the market and regulatory circumstances in these and other regions. We encourage the Commission to carefully research any claims that something like the LSE Obligation proposal has been implemented in another, similar region before gaining any comfort from them. In particular, the SPP experience is not applicable to ERCOT. There is a much higher degree of vertical integration in SPP, with much less retail choice, so resource adequacy obligations do not require many large capacity transactions, and market power is much less of a concern than it would be in ERCOT. In addition, SPP presently has substantial excess capacity; the pool anticipates a 21.8% installed reserve margin for 2022, compared to a target reserve margin of 12%.[2]

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[2] SPP, *2021 SPP Resource Adequacy Report*, June 15, 2021, p.3 (Available at https://spp.org/documents/64801/2021%20spp%20june%20resource%20adequacy%20report.pdf).

The Sierra Club appreciates the opportunity to file these comments in Project 52373. A brief Executive Summary Follows.

Sincerely,

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Executive Summary

The Sierra Club believes that the PUC can take some important steps in the coming months to improve our market, and its reliability and urges the Commission to take the following steps:

- Improve the ORDC, including switching from blended to seasonal curves, lowering the HCAP from $9,000 to somewhere between $4,500 and $6,000, and extending the MCP to 3,000 MWs;
- Expanding ERS, including its yearly budget, and considering allowing its use when reserves approach 3,000 MWs;
- Implement nodal prices for qualifying demand response resources;
- Begin a separate rulemaking to allow integration of distributed energy resources in energy and ancillary markets, including aggregation of these resources that are geographically near a single bus or node;
- Analyze and implement changes that can be made to Smart Meter Texas and within TDUs to increase access to telemetry data to expand the use of energy management system and demand response;
- Immediately begin a new project to consider changes to the scope, size and workings of the required energy efficiency and load management programs at the TDUs (25.181)
- Continue to move forward through the ERCOT process on implementing Fast Frequency Response, ERCS, changes to NSPS, and Real Time Co-Optimization;
- Analyze the costs and benefits of implementing a 30-minute or 60-minute Multi-Interval Real Time Market (MIRTM) as part of Real Time Co-Optimization

In addition, the Sierra Club believes there may be additional changes to ancillary services that may be needed, either by adding some differing duration products as part of NSPS/ECRS, or through the creation of an Uncertainty Product, similar to the concept proposed by the IMM.

We have major concerns and are currently opposed to the idea of the creation of Load Serving Entity Obligation or a Generation Firming Requirement. We believe it would take several years -- at least -- to implement, would be expensive to consumers, would be discriminatory to renewable energy, and would not guarantee reliability. We believe the LSE Obligation would lead to substantial market power that cannot be effectively monitored or (more importantly) mitigated, and that this will result in high prices and costs to satisfy the LSE Obligations, and discriminatory access to capacity.

A more targeted approach would be to require LSEs to provide a percentage of seasonal peak demand through demand response and customer-sited distributed generation resources, which fits more closely with their function in the market.

We also do not believe there is a great benefit in requiring a separate fuel-based winter reliability product, though we do believe that existing ancillary services could be modified to create some performance criteria to assure that ancillary products operate effectively in cold weather. We again salute the Commission for taking some initial positive action to require power plant and transmission winterization through a phased approach.

Finally, we call on the Commission to have at least one public hearing where any member of the public can provide verbal input on major proposals to change our market.